U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	PECO Nuclear Correspondence Control Desk P.O. Box 195 Wayne, PA 19087-0195
Facilities:	Limerick Generating Station, Units 1 and 2
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Dates:	July 6 through 10, 1998
Inspectors:	L. Briggs, Senior Operations Engineer, Team Leader W. Galyean, NRC Consultant, INEEL S. Hansell, Resident Inspector R. Latta, Senior Operations Engineer, HQMB, NRR A. Lohmeier, Senior Reactor Engineer C. Sisco, Operations Engineer
Approved by:	Richard J. Conte, Chief Operator Licensing and Human Performance Branch Division of Reactor Safety

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EXECUTIVE SUMMARY

This inspection involved a review of PECO Nuclear (PECO) implementation of the maintenance rule, as required by 10 CFR 50.65, at the Limerick Generating Station, Units 1 and 2. The report covers a one week onsite inspection by regional and headquarter's inspectors during the week of July 6-10, 1998.

The team concluded that although PECO had implemented the maintenance rule on July 10, 1996, it had only recently implemented a thorough program at the Limerick Generating Station, based on the following aspects:

- PECO had completed a thorough scoping review of all structures, systems and components under the scope of the maintenance rule in preparation for the NRC's maintenance rule inspection team. The licensee had identified, although extremely late, an additional 50 structures, systems and components and had correctly scoped them into their maintenance rule program (NCV 50-352/353-98-06-02). For those structures, systems and components that were excluded from the scope of the rule, justification was found to be acceptable.

- Use of the Limerick plant specific analysis (PSA) in verifying consistency between performance criteria and PSA assumptions was considered a strength; however, the lack of plant-specific reliability estimates in the PSA was considered a weakness. In addition, using specific failure-modes of single components to estimate the importance measure values of systems is contrary to the guidance given in NUMARC 93–01 and was concluded to be a weakness.

- The expert panel performed its assigned function in accordance with the program requirements and in an appropriate manner.

- System managers were knowledgeable of the maintenance rule requirements and industry operating experience applicable to their assigned systems.

- Structures systems and component performance criteria were, in general, conservatively established and were directly related to the probabilistic risk assessment assumptions. However two instances of failure to establish appropriate performance criteria (safety relief valves and fuel pool cooling system) are examples of a violation of 10 CFR 50.65 (a)(2) (VIO 50-352/353-98-06-01). The licensee had identified a similar violation in the control room emergency fresh air system. Extensive activities to get the maintenance rule program in compliance with requirements just prior to the inspection were evident.

- Corrective actions were taken when a structure, system, or component was identified as failing to meet its goal, performance criteria or experienced a maintenance preventable functional failure.

- Structures had been adequately scoped within the scope of the maintenance rule and were appropriately classified as (a)(2) systems. The performance criteria to move the classifications of structures into an (a)(1) status will be reviewed and revised as necessary by the expert panel.

- Based on the review of LGS's initial Unit 2 periodic evaluation and the subsequent Unit 1 assessment the team concluded that PECO had established appropriate provisions to satisfy the programmatic requirements of Procedure AG-CG-28.1 and paragraph (a)(3) of the rule. With respect to the initial periodic evaluation the team noted that the licensee had identified several events that reflected a weakness in the corrective action implementation process. The team also observed a problem relative to the untimely issuance of this document. Despite the problem with timeliness in issuing this periodic evaluation, the licensee had initiated corrective actions in response to the identified issues and the content of the assessment provided appropriate insights into the implementation of the maintenance rule process at LGS. Additionally, the team determined that the Unit 1 periodic evaluation had been issued within the licensee's established goal of 90 days, indicating an improvement in the review and issuance process associated with the (a)(3) assessments.

- The overall housekeeping and material condition of those SSCs selected for review were being maintained in good condition.

- Plant personnel knowledge of the maintenance rule program was good. The work control and on-line maintenance programs were coordinated to minimize the plant risk and used the Sentinel online risk computer model to assess equipment impact on plant risk. The licensee's process for assessing the risk associated with equipment outages (both at-power, and during shutdown) appears to be thorough and accurate. The work control process and online risk computer assessments were considered a strength.

- The licensee's nuclear quality assurance surveillance activities were comprehensive in nature and that these efforts were effective in identifying program implementation deficiencies. The maintenance rule self-assessment process was beneficial in documenting areas for improvement. However, PECO was very slow to implement the lessons learned from the Peach Bottom maintenance rule baseline inspection and to resolve deficiencies in its program.

Report Details

II. Maintenance

M1 Conduct of Maintenance (62706)

The inspection was conducted to verify that the implementation of the maintenance rule program, as required by 10 CFR 50.65, was effectively implemented at the Limerick nuclear generating station. The team used inspection procedure (IP) 62706, "Maintenance Rule," NUMARC 93-01, Revision 2, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and Regulatory Guide (RG) 1.106, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," as references during the inspection.

M1.1 Structures, Systems and Components (SSCs) Included Within the Scope of the Rule

a. Inspection Scope

The team reviewed the scoping documentation to determine if the appropriate SSCs were included within the maintenance rule program in accordance with 10 CFR 50.65(b). The team also reviewed the licensee's updated final safety analysis report (UFSAR), emergency operating procedures (EOP), AG-CG-28.1, Maintenance Rule Implementation Program, and the Limerick Generating Station (LGS) Maintenance Rule Scoping Bases Information documentation.

b. Observations and Findings

The team determined that, at the time of this inspection, PECO had adequately placed the requisite plant SSCs within the scope of the maintenance rule. However the team noted that the licensee had performed original scoping and issued a scoping list on July 1, 1995. Subsequent to the original scoping list (Revision 0) there were three revisions issued. Revision 1, issued March 31, 1998 (26 SSCs added); Revision 2, issued June 21, 1998 (22 SSCs added); and , Revision 3, issued July 8, 1998 (2 SSCs added). The three revisions added a total of 50 SSCs to the original scoping list. The team did not identify any additional SSCs that should have been included in the scope of the maintenance rule. Although extremely late the licensee's identification and inclusion of the additional 50 SSCs in the maintenance rule program scope was considered licensee identified and corrected. This item is considered a non-cited violation in accordance with the provisions of Section VII.B.6 of the enforcement policy (NCV 50-352/353-98-06-02).

c. Conclusions

PECO had completed a thorough scoping review of all structures, systems and components under the scope of the maintenance rule in preparation for the NRC's maintenance rule inspection team. The licensee had identified, although extremely late, the additional 50 SSCs and had correctly scoped them into their maintenance rule program (NCV 50-352/353-98-06-02). For those structures, systems and components that were excluded from the scope of the rule, justification was found to be acceptable.

M1.2 Safety (Risk) Determination and Risk Ranking

a. Inspection Scope

The team reviewed the methods the licensee established for making required safety determinations and setting goals commensurate with safety. Use of the Limerick Probabilistic Safety Assessment (PSA) to support the risk ranking and risk determination for Maintenance Rule applications was reviewed.

b. Observations and Findings

Safety or Risk Significance Determinations Methodology

The Limerick PSA is a conventional linked fault tree (small event-tree, large fault-tree) model and uses the NUPRA software (version 2.33 for DOS) for model development and analysis. There have been three updates of the PSA since the IPE version of the model. The most recent update was performed in late 1997 and early 1998. The revisions to the PSA model include, among other items, incorporation of plant-specific data for estimating initiating event frequencies and maintenance unavailability probabilities. However, failure rates (unreliability estimates), with few exceptions, do not utilize plant-specific experience. Nor is there any plan to generate plant-specific failure rates in the future. The PSA is used to help establish the risk significance of the SSCs covered by the maintenance rule (MR). The MR also requires a periodic assessment of the balancing between reliability and availability. Both of these processes would be better served by using plant-specific reliability estimates. The lack of plant-specific reliability estimates is considered a weakness by the team.

The licensee's approach for establishing risk significance of SSCs within the scope of the Maintenance Rule is to evaluate each SSC according to the three criteria specified in NUMARC 93-01 (risk achievement worth, risk reduction worth, and whether or not it falls within the 90% CDF contribution). These are then presented to the Expert Panel who make the final determination on the risk significance of each SSC within the MR scope. At issue here is the use of basic event (i.e., typically specific failure modes for specific components) importance measures to represent system level importance values. These importance measure values are then presented to the expert panel for use in determining SSC risk significance. While the expert panel has had some formal training in PSA (about 1-1/2 hours of instruction), the implications of this approach to estimating system level importance measures are not straightforward or easily understood. Because the expert panel does not rely solely on the PSA criteria for determining risk significance, a number of systems have been classified as risk significant even though they do not satisfy the PSA criteria. Nevertheless, the use of specific failure-modes of single components to estimate the importance measure values of systems is contrary to the guidance given in NUMARC 93–01 and is also considered a weakness by the team.

Performance Criteria

Performance criteria (PC) were developed using the flow chart presented on page 2 of 8 in AG-CG-28.1-7, Rev. 1. Limerick does not use the EPRI guidance for determining reliability PC, but takes a simpler and more conservative approach. The table below lists the reliability PC as specified by the Limerick guidance.

Type of System	Default Perf. Crit.	Acceptable PC
Highly Reliable	0 Maintenance Preventable Functional Failure	1 Maintenance Preventable Functional Failure with PSA analysis
Quantitatively Risk Significant (RS)	1 Maintenance Preventable Functional Failure	2 Maintenance Preventable Functional Failure with PSA analysis
Quantitatively not-RS (NRS, highly reliable	1 Maintenance Preventable Functional Failure	2 Maintenance Preventable Functional Failure based on SSC performance with PSA analysis
Expert Panel RS	1 Maintenance Preventable Functional Failure	2 MPFFs with SSC performance
NRS and reliable	1 Maintenance Preventable	2 MPFFs based on SSC performance
NRS and unreliable		2 MPFFs based on SSC performance
NRS, unreliable and large # of demands		2 or 3 MPFFs based on SSC performance

List of Highly Reliable Systems:

- Reactor vessel/internals
- Electrical buses
- RPS
- ARI
- ADS & other logic trains
- Batteries
- Primary containment
- Wetwell & drywell vacuum breakers

- SRVs
- Nuclear instrumentation
- CST
- CRD hydraulic control units

In only two cases was a risk-significant system approved for greater than the "default" PC values (per flowchart). Only the Agastat relays (system 100A) and the snubbers (system 103A) have reliability PC of greater than 1 Maintenance Preventable Functional Failure. Agastat relays for the Limerick site are segregated into two groups. One group comprises those relays associated with Unit-1 plus those relays shared by (common to) both Unit-1 and Unit-2. This group of relays has a reliability PC of less than 12 end-of-life failures per year. The second group of relays comprises those associated with only Unit-2. This has a reliability PC of less than 8 end-of-life failures per year. Snubbers have been assigned a reliability PC of 2 Maintenance Preventable Functional Failure (either functional test or visual inspection) per 24 months.

The system managers determine the unavailability PC. A four-year retrospective performance review was done to identify the historical yearly unavailability of the system/function. The unavailability PC is then the 95 percentile of the population distribution (i.e., distribution of the four yearly results) of this historical unavailability. (See AG-CG-28.1-8, Rev. 2)

Both the reliability and the availability PC were evaluated with respect to consistency with the PSA. When all the possible availability and reliability PCS are substituted into the PSA, the core damage frequency (CDF) increases 69%. When the reliability PCS alone are evaluated, the CDF increases 36%. When the availability PCS alone are evaluated, the CDF increases 22%. According to the EPRI PSA procedures guide (EPRI TR-105396, August 1995), permanent changes to the plant that result in a 56% (based on the base-case CDF for the Limerick PSA) increase in CDF would be acceptable. Since it is unlikely that the reliability of all PSA-modeled equipment will simultaneously degrade to the PC level, the primary concern is the effect of the availability PC. As shown above, the CDF increase is well within the guidelines set by the EPRI PSA procedures guide.

c. Conclusions

Use of the Limerick plant specific analysis (PSA) in verifying consistency between performance criteria and PSA assumptions was considered a strength; however, the lack of plant-specific reliability estimates in the PSA was considered a weakness. In addition, using specific failure-modes of single components to estimate the importance measure values of systems is contrary to the guidance given in NUMARC 93-01 and was concluded to be a weakness.

M1.3 Expert Panel

a. Inspection Scope

The team reviewed PECO procedure AG-CG-28.1 Revision 5 "Maintenance Rule Implementation Program" which detailed the responsibilities of the expert panel. The team also reviewed expert panel meeting minutes and attended an expert panel meeting.

b. Observation and Findings

The expert panel was comprised of members with experience in plant operations, maintenance, engineering and probabilistic risk assessment. The final decisions made by the panel were documented in the Maintenance Rule Scoping document. The expert panel reviewed and concurred with performance criteria, SSC's as (a)(1) or (a)(2), action plans for (a)(1) SSCs, and goals/monitoring results for (a)(1) SSCs.

The team reviewed the expert panel meeting agenda number 9814 and observed the expert panel meeting. The panel conducted a review of SSCs that were classified as (a)(1), reviewed functional failures and maintenance preventable functional failures and discussed previous action items. The team determined the expert panel performed its assigned function in accordance with the program requirements and in an appropriate manner.

c. Conclusion

The expert panel performed its assigned function in accordance with the program requirements and in an appropriate manner.

M1.4 (a)(1) Goal Setting and Monitoring and (a)(2) Performance Monitoring and Preventive Maintenance

a. Inspection Scope

The team reviewed program documents to evaluate the process established to set goals and monitor under (a)(1) and to verify that preventative maintenance had been demonstrated to be effective for SSCs under (a)(2) of the maintenance rule. The assessment on each SSC included a verification that goals and performance criteria were established in accordance with safety, that industry-wide operation experience was taken into consideration, that appropriate monitoring and trending were being performed, and that corrective actions were taken when an SSC failed to meet its goal, performance criteria, or experienced a maintenance rule functional failure. The team also discussed system performance as it related to the maintenance rule program and performed a system walkdown to assess material condition with the responsible system manager or designee. The team also verified the system managers knowledge as it pertained to the maintenance rule. The team assessed the following SSCs:

Emergency Diesel Generators, system 92A, (a)(1)
Reactor Water Cleanup, system 44, (a)(2)
HPCI, system 55, (a)(2)
Area Radiation Monitoring, system 27, (a)(2)
Agastat Relays, system 100A, (a)(1)
Control Room Emergency Fresh Air System, system 78B, (a)(1)
Safeguard Piping Fill System, system 52F, (a)(2)
SGTS, system 78E, (a)(2)
Nuclear Boiler, system 41A, (a)(1)
Fuel Pool Cooling System, system 53C, (a)(2)

Emergency Diesel Generator (EDG) System (System Number 92A)

The Unit 1 and Unit 2 EDGs were classified as (a)(1) systems. The team reviewed the MPFFs that had occurred in the systems and determined the goals established to return the systems to an (a)(2) status were appropriate. Based on discussions with the system manager, the team determined the manager was knowledgeable of the maintenance rule requirements and was familiar with industry events concerning EDGs. In addition, the team determined that extensive performance monitoring of the EDG systems was conducted. The monitoring was composed of extensive computerized records of various EDG system test results and operator round sheet information that was recorded with the system in operation as well as in standby. The information was trended and monitored with a low threshold of system parameter alarms to alert the system manager of potential adverse trends. The team conducted a walkdown of the Unit 1 and Unit 2 EDG systems and noted the material conditions of the systems was neat and orderly.

Reactor Water Cleanup System (RWCU) (System Number 44)

The RWCU system was classified as (a)(2) and was monitored on a plant level performance criteria of the loss of all system flow as a functional failure. The team concurred with the expert panel determination of the performance criteria for this system. The RWCU system performance was monitored by the computerized records of RWCU system test results and operator round sheet information that was recorded with the system in operation. The team conducted a walkdown of the system controls in the control room and found no problems with the system in operation.

High Pressure Coolant Injection (HPCI) System (System Number 55)

The HPCI system was classified as an (a)(2) system and had appropriate performance criteria established. No problems were identified during interviews with the system manager or during the system walkdown.

Area Radiation Monitors (System Number 100A)

The area radiation monitors (ARMs) were classified as an (a)(2) system and had appropriate performance criteria established. During discussions with the system manager it was determined that the ARMs had been placed "in scope" during revision 1 of the licensee's scoping activities. The inspector noted that the system had experienced numerous failures prior to 1996 due to quench gas problems with Geiger Muller (GM) detectors. The inspector questioned whether the system manager had brought this system to the Expert Panel to determine if it should be in the (a)(1) or (a)(2) category. It had not. The inspector noted that although the system had been performing satisfactorily for several quarters the "lookback" period would encompass a period of poor performance and should have received the expert panel's review. The system manager stated that this was an oversight (the system managers other system had been paneled) and took it to the expert panel during the week of the inspection. The expert panel agreed with the (a)(2) classification based on recent system performance. No other problems with the ARM system were identified.

Agastat Relays (System 27)

The Agastat relays were classified as a pseudo system and is in an (a)(1) status due to numerous age related maintenance preventable functional failures. The licensee made the Agastat relays a separate pseudo system and incorporated it into the maintenance rule program scope during revision 2 of the maintenance rule scoping list on June 21, 1998. The creation of the pseudo system was implemented to avoid classification of numerous systems in the (a)(1) status due to poor Agastat relay performance and to focus corrective actions on the source of the poor performance problems. Agastat relays interface with 27 different in scope SSCs. The inspector verified that Agastat relay functional failures were being counted in a manner that would not mask other SSC functional failures and result in improper classification and monitoring of system performance. Based on discussions with the system manager, observation of an expert panel meeting and documentation, the inspector determined that Agastat relay functional failures and interfacing SSC's unavailability times and/or functional failures were being properly accounted and tracked when Agastat relays were involved. The licensee was recently cited for failure to take corrective action concerning Agastat relay age and temperature related problems (NRC Inspection Report 50-352/353/98-05). The Agastat relay system's current performance goals appear appropriate and the latest failure rate data for the relays indicates a decreasing number of failures due to the ongoing relay replacement program. No problems were identified with the licensee's management of the Agastat relay system concerning application of maintenance rule requirements.

Control Room Emergency Fresh Air System (System 78B)

The CREFAS equipment, a standby system used to maintain control room habitability during postulated accidents, was scoped initially at the plant level and not risk significant on July 10, 1994. The 1994 expert panel noted that the CREFAS system was "qualitatively identified as risk significant." However, the panel reclassified CREFAS as not risk significant based on the ability of plant operators to open panel doors for mitigation of high temperature effects of a system failure.

The inspectors noted two problems with the classification of CREFAS. First, the expert panel's reclassification of the system as not risk significant was questionable because of the importance for the system to maintain control room habitability. In addition, the documentation used to support mitigation of high temperature effects provided a weak bases. Secondly, the team identified that the performance indicators were assessed incorrectly at the plant level instead of the train level as stated in NUMARC 93-01, section 9.4.1.2, "Train Level." Because the system was monitored at the plant level, the availability and reliability performance criteria were not tracked or monitored. This resulted in the CREFAS classification as an (a)(2) system until June 1998, when it was classified as risk significant. Due to the CREFAS risk significance status change from no to yes, the expert panel recognized that the system experienced more than one Maintenance Preventable Functional Failure in the prior two years. Exceeding one Maintenance Preventable Functional Failure for a risk significant system resulted in the CREFAS classification change to the (a)(1) status. The team concluded that the (a)(1) goals established for this system were acceptable and appropriate. Failure to establish appropriate system performance criteria is a licensee identified violation of 10 CFR 50.67.

Safeguard Piping Fill System (System 52F)

The safeguard piping fill system was classified as an (a)(2) system and had appropriate performance criteria established. No problems were identified during interviews with the system manager or during the system walkdown.

Standby Gas Treatment System (System 78E)

The standby gas treatment system was classified as an (a)(2) system and had appropriate performance criteria established. No problems were identified during interviews with the system manager or during the system walkdown.

Nuclear Boiler System, Safety Relief Valves (SRVs) (System 41A)

The SRVs are part of system 41A which also includes the main steam isolation valves (MSIVs), and reactor feedwater check valves (FWCVs). System 41A is considered safety significant and was classified as an (a)(1) system by the licensee due to an inadvertent blowdown of the Unit 1 RPV in 1995. The SRVs provide for reactor pressure vessel (RPV) over pressure protection for the RPV pressure boundary.

Although there have been no maintenance preventable functional failures (MPFFs) over the recent 24 months, the systems continue to be categorized as (a)(1) because of ongoing SRV pilot seat leakage and setpoint drift issues. Although the licensee's performance measures concerning setpoint drift would not result in placing the system in the (a)(1) category the licensee recognizes that setpoint drift is an ongoing problem. Specifically, SRVs at Limerick are part of an industry wide performance problem due to pilot seat leakage and setpoint drift issues of Target Rock 2 stage relief valves.

Review of the Limerick SRV setpoint drift data indicated that 12 of 14 Unit 1 SRVs measured during 1RO7, after operation from February 1996, through April 1998, had setpoint drift ranging from 1.62% to 6.36% above the technical specification (T S) limit of +or- 1%. Three Unit 1 SRVs were also reported to have leaks.

The team also reviewed the setpoints measured on 14 Unit 2 SRVs during 2RO4, after operation from February 1995, through February 1997, and found that 11 valves had setpoints ranging from 1.27% to 13.45% over the Technical Specifications limit of +or- 1%. In addition one SRV was reported as having gross N2 leakage with minimal steam leakage, and another had minor leakage.

A concern with setpoint drift has been the possible consequence of RPV over pressure during an upset operating condition. General Electric studies of this concern provided calculated assurance that the peak RPV pressure with reported setpoint drift of Unit 2 SRVs after 2RO4 was 1340 psig, bottom head, and the peak dome pressure was 1318 psig. These pressures are marginally below the respective limits of ASME (1375 psig), and Technical Specifications Section 2.1.3 dome pressure Safety Limit (1325 psig). These pressures were calculated from tests performed by an independent laboratory.

The inspection team noted that the as-found setpoint test results, performed at the end of the operating cycle, indicated that most SRVs exceeded the Technical Specifications, Section 4.4.2, surveillance requirement for maximum setpoint pressure allowed. Furthermore, the closeness of the calculated RPV pressures resulting from setpoint drift to the ASME limit (1340/1375 psig) and Technical Specifications dome pressure Safety Limit (1318/1325 psig) was a concern to the team. It is not clear to the inspection team that future setpoint drift would not result in computed pressures exceeding these limits.

As part of an effort to resolve the SRV setpoint drift problem, Limerick had installed platinum doped (3%) pilot valve seats in 5 Unit 1 SRVs and 6 Unit 2 SRVs. The setpoint test results of 1RO7 and 2RO4 showed no improvement in setpoint drift in Units and 2.

Limerick action request A0959089 states that the setpoint drift and seat leakage issue can be resolved through a change in SRV design to a 3 stage pilot valve design. Accordingly, 14 SRVs with the revised pilot valve design are currently scheduled to be installed in unit 1 during 1RO8 and unit 2 during 2RO5.

The inspection team reviewed the performance indicator bases for the SRV. The SRV component maintenance functional failure is defined as an inadvertent lift of a single SRV at power, or the failure of any groupings of SRVs to lift, such that the maximum RPV pressure is challenged. A significant adverse trend would require (a)(1) consideration. The team found the performance measure established by the licensee to prevent RPV over pressurization would not allow adequate monitoring of system performance such that the SRVs would remain capable of performing their intended function as required. Specifically, the licensee established performance measure would have allowed the licensee to exceed the TS Safety Limit of 1325 psig RPV dome pressure without identifying inadequate SRV performance (VIO 50-352/353/98-06-01). Other performance criterion were acceptable.

Fuel Pool Cooling and Cleanup System (System 53C)

As described in the Updated Final Safety Analysis Report the fuel pool cooling and cleanup (FPCC) system for each unit primarily consists of the pool water collection equipment, a normally operating cooling train with two heat exchanges and two pumps, a cleanup loop, and the discharge difusers in the spent fuel pool. Additionally, a manually operated backup (standby) heat exchanger and pump are included in the system. The spent fuel pool is also provided with redundant seismic Category I makeup capability, through a cross-connecting line to the residual heat removal system, to ensure an adequate supply of makeup water under conditions of maximum anticipated evaporation associated with fuel pool boiling.

Based on the review of the licensee's documentation the team determined that the FPCC system, currently classified as (a)(2), was recently added to the scope of the licensee's maintenance rule program as a result of Revision 2 to procedure AG-CG-28.1-2, "Limerick Generating Station (Peach Bottom) Maintenance Rule Scope," dated June 21, 1998. The inspection team also reviewed the operating history of both Unit 1 and 2, FPCC systems beginning with failure of the Unit 1 pump motor 1A-P21 in 1992. As a result of this review the team determined that the original Unit 1 motors had been replaced with motors from a different vendor over the period from October 1992, through January 1993. However, during the period from February 1993 through June 1996, the replacement motors experienced four failures as a result of high vibration caused by lower motor bearing failure due to the use of inappropriate grease and inadequate lubrication frequency. During this same period there were also instances of manufacturing and assembly deficiencies that required motor replacement. As indicated in the applicable work documents, corrective actions were initiated by the licensee to resolve the lubrication deficiencies associated with the Unit 1 pump motors and to replace the motor on the pump that failed due to manufacturing and assembly deficiencies.

With respect to the Unit 2 FPCC system, the team determined that the licensee had implemented appropriate corrective actions associated with the control of pump motor lubricants and that no further failures had been attributed to this condition. However, the team noted that two of the three FPCC system pump motors for Unit 2, had experienced failures during the period from March 1992 through February 1996. These additional FPCC pump motor failures, which were similarly attributed to manufacturing and assembly defects, had been corrected by replacing the failed components with motors from an alternative supplier without further evaluation.

As a result of the multiple failures associated with the FPCC pump motors, the team examined the licensee's established performance or condition measures which are designed to demonstrate that effective preventive maintenance was performed on this system. Based on this review, the team determined that the licensee had defined the failure of the FPCC system in terms of total loss of its intended function. Specifically, the licensee established the entry into off normal procedure ON-125, "Loss of Fuel Pool Cooling," which involves a total loss of the system function (i.e., capability to maintain fuel pool temperature) as the basis for defining the system performance measures. Accordingly, the team determined that the performance criteria selected was inadequate in that (1) it allowed the system to degrade to a point where it would be incapable of fulfilling its intended function, and (2) it effectively "masked" multiple component failures (i.e., repeated system failures and/or the loss of a stand-by system.) Accordingly, the licensee had failed to establish appropriate performance measures for the SFCC and was therefore unable to effectively demonstrate that the SFCC remained capable of performing its intended function, (VIO 50-352/353/98-06-01).

Structures

The structural monitoring program was defined in procedure AG-CG-28.1 "Maintenance Rule Implementation Program," Exhibit AG-CG-28.1-11, "Maintenance Rule Structural Monitoring Program." The team reviewed this procedure, the program documentation, and conducted in depth discussions with the system manager. The team determined that structures had been adequately scoped within the scope of the maintenance rule. The team reviewed the documentation of the results of the baseline walkdown inspections of the structures. The team noted the baseline inspections were completed in June, 1998. The team's review of this documentation indicated that the walkdowns were thorough and provided an adequate basis to evaluate the condition of the structures. The structural monitoring program requires the walkdown to be conducted every four years. All structures had been classified as (a)(2) based on the condition of the structures. The structural monitoring program criteria to move a structure from the (a)(2) classification into the (a)(1) classification was at the level of a functional failure of the structure. Based on discussions with the system manager, the criteria to move a structure into the (a)(1) classification would be reviewed and revised as necessary after consultation with the expert panel.

c. Conclusions

System managers were knowledgeable of the maintenance rule requirements and industry operating experience applicable to their assigned systems.

Systems, structures and components performance criteria were, in general, conservatively established and were directly related to the probabilistic risk assessment assumptions. However two instances of failure to establish appropriate performance criteria (safety relief valves and fuel pool cooling system) are examples of a violation of 10 CFR 50.65 (a)(2)(VIO 50-352/353-98-06-01). The licensee had identified a similar violation in the control room emergency fresh air system. Extensive activities to get the maintenance rule program in compliance with requirements just prior to the inspection were evident.

Corrective actions were taken when a SSC was identified as failing to meet its goal, performance criteria or experienced a Maintenance Preventable Functional Failure.

Structures had been adequately scoped within the scope of the maintenance rule and were appropriately classified as (a)(2) systems. The performance criteria to move the classifications of structures into an (a)(1) status will be reviewed and revised as necessary by the expert panel.

M1.5 Periodic Evaluations (a)(3)

a. Inspection Scope

Paragraph (a)(3) of the maintenance rule requires that performance and condition monitoring activities and the associated goals and preventive maintenance activities be evaluated taking into account, where practical, industry-wide operating experience. This evaluation is required to be performed at least one time during each refueling cycle, not to exceed 24 months between evaluations. The licensee's administrative controls, related to the 10 CFR 50.65 (a)(3) periodic evaluation process are described in Procedure AG-CG-28.1, "Maintenance Rule Implementation Program," Revision 5.

b. Observations and Findings

In order to evaluate the adequacy of the PECO's periodic evaluation process the team reviewed the Limerick Generating Station (LGS), Unit 2 , "Maintenance Rule Periodic Assessment," dated December 30, 1997, which documented the licensee's initial (a)(3) periodic evaluation. Specifically, this assessment addressed the implementation of the rule for LGS Unit 2, for the period of February 1, 1995, through January 31, 1997. As determined by the team, the assessment appropriately summarized the status of the four systems for which goals had been established under paragraph (a)(1) and properly characterized the performance of SSCs monitored under paragraph (a)(2) of the rule.

During the review of the Unit 2 periodic evaluation, the team noted that the Main Steam Safety Relief Valves (SRVs), which are part of the Nuclear Boiler System (41A), were not identified as an (a)(1) system, despite the licensee's current characterization of System 41A as being in (a)(1) for both units. Specifically, as documented in PEP 10004442, the "M" SRV experienced a spurious lift on September 11, 1995, and failed to reseat which resulted in the Nuclear Boiler System (for both units) being placed in an (a)(1) status with goals and action plans defined in A/R A0959089. In response to this issue the licensee stated that the earliest documentation of the Unit 2 SRVs being classified as (a)(1) appeared in the second quarter 1997 System Health Reports. However, as indicated by the licensee the Improvement Plan described in A/R A0971931 included corrective actions for the SRVs in both Units 1 and 2. Therefore, the team determined that the impact of not explicitly listing System 41A as an (a)(1) in the Unit 2 periodic evaluation was negligible.

The team also noted that although the Unit 2 maintenance rule periodic evaluation had been completed within the prescribed time frame it had not been issued until eleven months after completion of the 24 month evaluation cycle. As described by the licensee the basis for this delay was a combination of competing priorities and the expert panels focus on emergent issues. However, the team informed the licensee that the (a)(3) provisions of the rule, were intended to capture operational data based on a refueling cycle and to make this information available to utility management, in a timely manner, such that the effectiveness of maintenance activities could be determined.

Notwithstanding the lack of timeliness in issuing the Unit 2 periodic evaluation, the team determined that the licensee had adequately addressed the requirements of Procedure AG-CG-28.1 and paragraph (a)(3) of the rule for the specified period and that the associated corrective actions described in the respective improvement plans were appropriate.

Additionally, the team examined the results of the Unit 1 periodic evaluation, dated July 1, 1998, which covered the period from April 1, 1996, through March 31, 1998. The team determined that the assessment provided appropriate information related to the implementation of the maintenance rule process and that the evaluation adequately addressed the monitoring of established goals for the five Unit 1 systems classified as (a)(1). The team also determined that appropriate performance measures had generally been established, and that acceptable technical determinations had been documented for identified deficiencies. The periodic evaluation also discussed the balancing of availability and reliability, the effectiveness of removing equipment from service and various elements related to the demonstration of effective maintenance. Overall the licensee had established a conservative process for developing goals for SSCs under paragraph (a)(1) of the rule. The team also ascertained, for the cases inspected, that corrective actions had been effective in improving the performance of systems identified for goal setting during the assessment period. Relative to the establishment of performance measures for SSCs covered under paragraph (a)(2) of the rule, the licensee's process for identifying declining trends was appropriate in that the systems classified as (a)(2) did not exceed their performance measures or exhibit an adverse trend without appropriate supporting analysis during the evaluation period. The team observed that the documented periodic evaluation indicated that several events analyzed during the period reflected a weakness in the corrective action implementation process which required management attention. The team also noted that corrective action implementation problems had been identified by the NRC in prior inspection reports.

c. Conclusions

Based on the review of LGS's initial Unit 2 periodic evaluation and the subsequent Unit 1 assessment the team concluded that PECO had established appropriate provisions to satisfy the programmatic requirements of Procedure AG-CG-28.1 and paragraph (a)(3) of the rule. With respect to the initial periodic evaluation the team noted that the licensee had identified several events that reflected a weakness in the corrective action implementation process. The team also observed a problem relative to the untimely issuance of this document. Despite the problem with timeliness in issuing this periodic evaluation, the licensee had initiated corrective actions in response to the identified issues and the content of the assessment provided appropriate insights into the implementation of the maintenance rule process at LGS. Additionally, the team determined that the Unit 1 periodic evaluation had been issued within the licensee's established goal of 90 days, indicating an improvement in the review and issuance process associated with the (a)(3) assessments.

M2 Maintenance and Material Condition of Facilities and Equipment

a. Inspection Scope

The team performed walkdowns of those systems in which vertical slice inspections were performed. These system walkdowns were performed with the responsible system manager or designee. During the walkdowns the teams observed the material condition of the SSCs.

b. Observations, and Findings

The team performed material condition walkdowns of selected portions of those SSCs selected for detailed reviews. Housekeeping in the general areas around systems and components was good in the plant areas toured. The material condition of the equipment observed was acceptable and function did not appear to be impaired. System engineers were cognizant of their system responsibilities, which included an awareness of the material conditions for those systems in which they were assigned.

c. Conclusions

The overall housekeeping and material condition of those SSCs selected for review were being maintained in good condition.

M.4 Staff Knowledge and Performance

M4.1 Safety assessments Before Taking Equipment Out-of-Service for On-Line Maintenance and Staff Knowledge of the Maintenance Rule Program

a. Inspection Scope

The team interviewed engineers, managers and licensed operators to assess their understanding of the maintenance rule and associated responsibilities. In addition, paragraph (a)(3) of the rule states that the total impact on plant safety should be taken into account before taking equipment out of service for monitoring or maintenance. The team reviewed the applicable work control procedures and discussed the process and procedures with appropriate PECO Nuclear personnel, including licensed operators and PSA representatives.

b. Observations and Findings

Programs

The program for assessing plant safety during equipment outages is described in Procedure AG-43, "Guideline for the Performance of System Outages." The process provided several mechanisms for assessing and limiting the plant impact of equipment removed from service including: a computer based risk assessment model, ORAM-Sentinel, provided real time equipment out of service risk impact capabilities, procedural restrictions prohibited the concurrent removal of specific systems from service based on their contribution to the probabilistic core damage frequency, Technical Specification limitations, multi-disciplined schedule reviews and operating experience input. The 13 week work control process was detailed and refined each week to ensure that plant risk was minimized and work was coordinated for each day. Planning and scheduling were balanced to ensure that maintenance and operational requirements provided the highest equipment reliability and availability.

ORAM-Sentinel (outage risk assessment management software package used by the licensee) is actually two separate programs linked only in the similarity of the user interface. ORAM is for shutdown applications, and has been used at Limerick since approximately 1992. Sentinel is for at-power applications, and has been used at Limerick since approximately 1995. The two systems were merged by EPRI about 1997.

Both ORAM and Sentinel use a qualitative, defense-in-depth system based on simple logic models. For each safety function a simple fault-tree OR-gate lists all redundant systems/trains capable of providing the safety function. Sentinel (the at power system) tracks the following safety functions:

Reactivity Control
High Pressure Injection
RPV Pressure Control
Low Pressure Control
Primary Containment Heat Removal
Secondary Containment
Primary Containment Integrity
Electric Power
Control Enclosure Habitability.

Defense-in-depth status is color coded (for both Sentinel and ORAM) based on the amount of redundancy available for each safety function. The colors and associated meaning are listed below.

Green – Acceptable risk category
Yellow – Slightly higher risk
Orange – Significant risk caused by several risk significant activities scheduled simultaneously
Red – Not permitted for planned work.

In addition, Sentinel includes a quantitative PSA component consisting of a library of pre-analyzed sensitivity analysis results that quantify the effect on CDF of different equipment outage configurations. Note that this library (of approximately 400 configurations) requires updating whenever the PSA is updated. Sentinel uses a color code to display the risk significance (CDF ranges) of different equipment outage configuration.

White – Unanalyzed configuration
Green – CDF = 2.7E-6 (base case) to 6E-6
Yellow – CDF = 6E-6 to2.5E-5
Orange – CDF = 2.5E-5 to 5E-5
Red – CDF > 5E-5

Emergent work is updated in Sentinel on a daily basis. If a particular configuration has not been analyzed (i.e., White color code), the PSA group can perform the sensitivity analysis in about 24-hours. However, note that the qualitative, defense-in-depth indicator is immediate and based on the inspectors limited check performed during the inspection, seems to be conservative relative to the CDF indication.

ORAM monitors the following safety functions:
Shutdown Cooling
Inventory Control
Electric Power Control
Reactivity Control
Primary/Secondary Containment
Fuel Pool Cooling
Vital Support Systems

There is no shutdown risk assessment; therefore ORAM has no quantitative risk assessment component.

Personnel

The team found that outage planning personnel and licensed operators were knowledgeable about the on-line maintenance and maintenance rule program requirements. The work control organization evaluated plant risk at the morning work control meeting and factored in the impact of unexpected equipment failures when they occurred. All personnel in the maintenance planning, outage work control, and operations clearance and tagging process understood the significance of the their role in the implementation of the maintenance rule program.

c. Conclusions

Plant personnel knowledge of the maintenance rule program was good. The work control and on-line maintenance programs were coordinated to minimize the plant risk and used the Sentinel online risk computer model to assess equipment impact on plant risk. The licensee's process for assessing the risk associated with equipment outages (both at-power, and during shutdown) appears to be thorough and accurate. The work control process and online risk computer assessments were considered a strength.

M7 Quality Assurance (QA) in Maintenance Activities

a. Inspection Scope

The team reviewed the results of recent maintenance rule surveillances and self-assessments in order to determine if the provisions of the maintenance rule were being properly implemented.

b. Observations and Findings

In particular, the team examined Surveillance Report LSR-97-0258 which documented the results of PECO Nuclear Quality Assurance (NQA) assessment of the implementation of the maintenance rule at LGS. This surveillance report which was conducted between November 12, 1997, and January 14, 1998, identified numerous deficiencies related to the adequacy of the maintenance rule program at LGS including the failure to properly incorporate the lessons learned from the Peach Bottom MRBI. The team reviewed the current status of these deficiencies which were documented on PECO Energy Company (PEP) Issue Number I0007808. As a result of this review the team determined that the eight deficiencies identified during the surveillance fundamentally involved PECO's late implementation of maintenance rule program controls at LGS. The inadequacies associated with the implementation of the maintenance rule at LGS were also closely linked to the deficiencies identified during the MRBI at Peach Bottom in August of 1996. Accordingly, the corrective actions for both Peach Bottom and LGS were initially directed at a common resolution process. However, as indicated in the surveillance report, subsequent to the Peach Bottom MRBI enforcement conference, on November 15, 1996, LGS management decided to not concentrate resources on improvements to the maintenance rule program at that time in order to focus on the upcoming Unit 2 refueling outage.

On February 19, 1997, PEP I0006028 (evaluation number 17 to incorporate Peach Bottom lessons learned) was assigned to LGS with a due date of June 1, 1997. On May 27, 1997, a response to PEP I0006028 (evaluation number 17) was provided which documented that the deficiencies discovered during the Peach Bottom MRBI were in the process of being incorporated into the LGS maintenance rule program. Subsequent to this response four successive extensions were granted (in May, June, August and September of 1997) to the Operations Experience Assessment Program (OEAP) A/R associated with the resolution of this issue. Ultimately the OEAP A/R was closed out after a maintenance rule implementation A/R (A1110145) was created. However, as determined by the team many of the substantive evaluations associated with this A/R were not completed until the first and second quarters of 1998. Prompt resolution of the generic issues associated with PEP I0006028 would have improved maintenance rule implementation at LGS. Many of the corrective actions associated with PEP I0007808, dated January 13, 1998, which were subsequently corroborated by an independent team assessment performed from February 20 - 27, 1998, were not effectively resolved until the second quarter of 1998. The team determined that PECO was inordinately slow to incorporate the requirements of the maintenance rule at LGS because of the protracted implementation of corrective actions related to the assimilation of lessons learned from the Peach Bottom MRBI and the delayed technical resolution of the programmatic deficiencies documented on PEP I0007808.

c. Conclusions

The licensee's NQA surveillance activities were comprehensive in nature and that these efforts were effective in identifying program implementation deficiencies. The maintenance rule self-assessment process was beneficial in documenting areas for improvement. However, PECO was very slow to implement the lessons learned from the Peach Bottom maintenance rule baseline inspection and to resolve deficiencies in its program.

V. Management Meetings

X1 Exit Meeting Summary

The team discussed the progress of the inspection with PECO representatives on a daily basis and presented the inspection results to members of management at the conclusion of the inspection on July 10, 1998.

The team asked whether any materials examined during the inspection should be considered proprietary. The utility indicated that none of the information provided to the team was considered proprietary.

X1.1 Final Safety Analysis Report Review

A recent discovery of a licensee operating their facility in a manner contrary to the Final Safety Analysis Report (FSAR) description highlighted the need for a special focussed review that compares plant practices, procedures, and parameters to the FSAR descriptions. While performing the inspection discussed in this report, the team reviewed selected portions of the FSAR. The team did not identify any discrepancies.

PARTIAL LIST OF PERSONS CONTACTED

PECO Energy

G. Angus, Plant Engineering, Maintenance Rule Coordinator
M. Alderfer, Senior Manager Plant Engineering
F. Cook, Senior Manager Design Engineering
M. Gallagher, Plant Manager
C. Gerdes, Manager, Plant Engineering, ECCS
J. Grimes, Director, Engineering
G. Krueger, Peach Bottom PSA
R. Porrino, Maintenance Manager
T. Tonkinson, Experience Assessment
J. VonSuskil, Vice President
V. Warren, Limerick PSA
T. Wilson, ORAM-Sentinel coordinator

NRC

S. Barr, Reactor Engineer, Region I
S. Black, Chief, Quality Assurance, Vendor Inspection, and Maintenance Branch, NRR
A. Burritt, Senior Resident Inspector, Limerick
R. Conte, Chief, Operator Licensing/Human Performance Branch, Region I
R. Correia, Chief, Reliability and Maintenance Section, NRR

LIST OF INSPECTION PROCEDURES

IP 62706 Maintenance Rule

LIST OF ITEMS OPENED and CLOSED

Number	Type	Description
Open		
50-352/353-98-06-01	VIO	Licensee failed to establish adequate performance measures for SSCs and was therefore unable to effectively demonstrate the SSCs remained capable of performing their intended function (two examples).
Closed		
50-352/353-98-06-02	NCV	Licensee identified that they had failed to incorporate 50 SSCs into the scope of the maintenance rule program in July 1996.

PROCEDURES AND DOCUMENTS REVIEWED

AG-CG-28.1, Rev. 5, Maintenance Rule Implementation Program

AG-CG-28.1-2(-1), Rev.2, Limerick Generating Station (Peach Bottom) Maintenance Rule Scope

AG-CG-28.1-3, Rev.2, Rules for Governing Expert Panel Activities

AG-CG-28.1-4, Flowchart for Performance Indicator Selection

AG-CG-28.1-5, Rev. 1, PECO Energy Approach to Use MPFF for Maintenance Rule Performance Monitoring

AG-CG-28.1-6, PECO Energy Approach When Setting Acceptable Performance Levels for Monitoring MPFF

AG-CG-28.1-7, Flowchart for Setting Acceptable Levels for Monitoring MPFF (Reliability performance criteria)

AG-CG-28.1-8, Flowchart for Selecting Acceptable Levels for Monitoring Unavailability

AG-CG-28.1-9, Guidance for Identifying and Evaluating MPFFs

AG-CG-28.1-11(-10), Limerick Generating (Peach Bottom Atomic Power) Station Maintenance Rule Structural Monitoring Program

LR-C-10, Performance Enhancement Program

AG-43, Rev. 15, Guideline for the Performance of System Outages

OSG-404, Online Risk Assessment Using ORAM-Sentinel

OSG-117, Guideline for Outage Planning and Risk Management

PECO Energy Company Memorandum, from Victoria Warren to Virginia Angus, dated May 15, 1998.

LIST OF STANDARD ACRONYMS

AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ANI	American Nuclear Insurers
AOV	Air Operated Valve
AR	Action Report
ASME	American Society of Mechanical Engineers
CAFTA	Computer Assisted Fault Tree Application
CCW	Component Cooling Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CM	Corrective Maintenance
CR	Control Room
CVCS	Chemical and Volume Control System
EAC	Experience Assessment Coordinator
ECR	Engineering Change Request
EDG	Emergency Diesel Generator
EOOS	Equipment Out-of-Service
EOPs	Emergency Operating Procedures
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
EWR	Engineering Work Request
FF	Functional Failure
FHA	Fire Hazards Analysis
FPE	Fire Protection Engineer
FV	Fussell-Vesely
GET	General Employee Training
HVAC	Heating Ventilation and Air Conditioning
IFI	Inspector Follow-up Item
IP	Inspection Procedure

IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
ITS	Improved Technical Specification
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERFs	Large Early Release Fractions
LOCA	Loss of Coolant Accident
LTOP	Low Temperature Over Pressure Protection
MOV	Motor-Operated Valve
MPFF	Maintenance Preventable Functional Failure
MR	Maintenance Rule
NI	Nuclear Instrument
NORMS	Nuclear Operations Records Management System
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSARB	Nuclear Safety Audit and Review Board
NUMARC	Nuclear Utility Management and Resource Council
NUSCo	Northeast Utilities Service Company
OEAP	Operating Experience Assessment Program
OSTI	Operational Safety Team Inspection
PC	Performance Criteria
PCN	Procedure Change Notice
PCR	Procedure Change Request
PEP	Performance Enhancement Program, see LR-C-10
PI	Program Instruction
PIMS	Plant Information and Monitoring System
PMEA	Periodic Maintenance Effectiveness Assessment
PORC	Plant Operations Review Committee
PORV	Power-Operated Relief Valve
ppm	parts per million
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
PT	Periodic Test
QA	Quality Assurance
QAOR	Quality Assurance Occurrence Reports
QC	Quality Control
RAT	Risk Assessment
RAW	Risk Achievement Worth
RCA	Radiologically Controlled Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG&E	Rochester Gas and Electric Corporation
RHR	Residual Heat Removal
RP&C	Radiological Protection and Chemistry
RPS	Reactor Protection System
RRW	Risk Reduction Worth
RWST	Refueling Water Storage Tank

SAB	Safety Analysis Branch
SAFW	Standby Auxiliary Feedwater System
SBO	Station Blackout
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SSCs	Structures, Systems and Components
ST	Surveillance Test
TCP	Transient Combustibles Permit
TGM	Toxic Gas Monitor
T/PM	Test/Preventive Maintenance
TS	Technical Specifications
TSC	Technical Support Center
UCLF	Unplanned Capability Loss Factor
UFSAR	Updated Final Safety Analysis Report
UL	Underwriter's Laboratory
URI	Unresolved Item
VAC	Volts Alternating Current
VIO	Violation